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MATHEMATICAL SPACE MODEL OF THE ZOTTI FIELD IN ALGERIA

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ABSTRACT

The study of the Zotti field was performed as a part of the "The Algerian Hydrocarbon Development Master Plan"[1] in conjunction with the personnel of SONATRACH to investigate alternative methods of increasing the oil recovery from the field. This study is an example of the detailed work that is being performed in this overall planning effort. Also it illustrates how the geological description of a relatively small field with wide spacing, strong water drive, and a small amount of production and pressure drop was significantly improved by the use of a mathematical space model.

INTRODUCTION

The Zotti field, sometimes referred to as El Agreb Northeast, is one of three fields formed along a series of faulted anticlines located on the east flank of the Oued Mya basin. The fields are located in the Algerian Sahara approximately 100 kilometers southwest of Hassi Messaoud and 350 kilometers west of the Tunisian border as shown on Figure 1. The Zotti field lies between two fields, El Gassi to the northeast and El Agreb to the southwest.

An early interpretation of the geology of the area was described by Ali[2] and several re-interpretations have been made as new data was added. The reservoir rock is low porosity and permeability sandstones and shales of Cambrian and Ordovician age. No free gas was initially present in the reservoir, and the produced oil has a stock tank gravity of 45^{o} API.

The principal objectives of this study were to determine the amount of oil-in-place and potential recoveries using various methods of development. This was accomplished through detailed geological and engineering studies of the basic data and using a mathematical space model to simulate the field history by adjusting the data within known or expected limits. The first set of history matching runs were designed to determine the sensitivity of the various data. These runs indicated that the relative permeability curves had to be adjusted beyond expected limits and the reservoir was substantially larger than what was originally described with well control and geophysical data. The history was matched with the greatly adjusted data and a prediction case was run. The results of this case indicated that the oil recovery percentage would be greater than normally expected. Later a delineation well was drilled which showed that the reservoir was larger than initially described. The new geological data increased the oil-in-place 38 percent and a re-match was made. An excellent agreement exists between the new oil recoveries and published correlations. Both the original and the final matches were good, which indicated that it is important to explore the sensitivity of the data for this type of reservoir. This was discussed by Hirasaki[3] in his report on estimation of data parameters in the displacement process.

The following paper summarizes the study and reports the unique ability of a space model to study this type of problem and reports the general conclusions of the work.

GEOLOGY

The structural highs of the El Gassi, Zotti and El Agreb fields lie in an area approximately 50 kilometers long and 15 kilometers wide, trending in a northeast-southwest direction. It appears that the reservoirs are connected by a common aquifer. However, pressures calculated by the Reservoir Performance Simulator indicate that there is no significant pressure communication between the reservoirs. This is due to the apparent low permeability that exists away from the crests of the structures and the presence of faults between the reservoirs. For all practical purposes the development of these reservoirs can be carried out independently.

The crest of the structure has been truncated by Hercynian erosion and the rock qualities are generally better closer to the erosion surface due to the effects of groundwater solution. The reservoir rock is composed of low porosity and low permeability sandstones and shales of Cambrian and

References and illustrations at end of paper

Ordovician age. The Ordovician strata is relatively impermeable and attempts to produce from it have been unsuccessful. The Cambrian layers have good reservoir qualities at the top of the section which become poorer with depth. The strata of this period are divided into the R1, R2, and R3 zones according to the accepted stratigraphic nomenclature of the region. Two layers were selected for simulation of reservoir performance in this study. The upper layer consists of the R1 and R2 zones, and the lower layer is made up of the R3 zone. The selection was based partly on stratigraphic divisions but primarily on differences in the reservoir rock characteristics. All of the oil is contained in the upper Cambrian R1-R2 layer. The depth to the top of this layer is 2995 meters subsea. The depth to the initial oil-water contact was 3065 meters, resulting in a maximum initial oil zone thickness of 70 meters. The R1-R2 layer has an average porosity of about 8 percent and an average permeability of 15 millidarcies. The R3 layer has an average porosity of about 5 percent and permeability of about 0.3 millidarcies. Table 1 lists the important characteristics of the Zotti field. Figure 2 is a cross-section of the field. Figure 3 is a structure map on top of the R1-R2 layer and Figure 4 is a net oil isopach map of this layer. The R3 layer, which is primarily water saturated, is essentially an expansion zone, while the R1-R2 layer is a flow zone. Each layer averages about 150 meters in gross thickness. In the R1-R2 layer both edge water displacement, and to a lesser degree, bottom water displacement are occurring. This concept was confirmed during the history matching of the wells in each of the fields. No evidence of field-wide barriers to vertical or horizontal flow was observed.

DEVELOPMENT HISTORY

The Zotti field was discovered by the French company, Société Nationale des Pétroles d'Aquitaine (SNPA), in 1959 after seismic reconnaissance indicated an anticlinal high in the Precambrian basement. It was originally hoped that this area would become another Hassi Messaoud. In November 1959, AR-1 was drilled and completed as the discovery well of Zotti. By 1975 a total of nine wells had been drilled in the field. Three additional development wells were drilled in 1977 and 1978, which included AR-61 drilled during the course of the study.

In general each well has 13 3/8 inch casing set to a depth of about 250 meters, if mud loss occurred. Casing of 9 5/8 inches was set to a depth of about 2500 meters to isolate the Jurassic water formations and 7 inch casing was set to the top of the Cambrian. The wells were completed by drilling into the producing formation with a 5 15/16 inch core bit. With the exception of AR-61, all wells were open hole completions. Slotted liners have been installed in a number of wells and AR-61 was completed through perforations in a cemented liner. All of the wells have 4 inch tubing.

The logging program was complete and fairly consistent. Most wells have Laterologs and Microlaterologs, Sonic and Gamma Ray-Neutron logs.

In general, good production and pressure data have been collected with the exception of water production which is difficult to measure. As of January 1, 1978, a total of 10.1 million stock tank cubic meters of oil had been produced or about 14.5 percent of the initial oil-in-place. Production for the field has risen erratically with the drilling of each new well. By the end of 1977 the field was producing at a rate of 3600 cubic meters per day. A plot of the historical reservoir performance is shown in the first part of Figure 5. The average production of eight of the nine wells drilled by 1975 was greater than 1.2 million cubic meters or about 7.5 million barrels per well. The discovery well, AR-1, encountered an area of very poor reservoir qualities and produced only about 850 cubic meters of oil before being shut-in. Examples of individual well production and pressure performance appear in Figure 6. The average pressure drop for the field during the history period was 81 kg/cm^2 or about 18 percent of the original reservoir pressure. Principal sources of primary energy have been from both edge and bottom water influx, and to a limited extent from the expansion of the reservoir rock and fluids.

HYDROCARBON DATA AND INITIAL OIL-IN-PLACE

The gravity of the stock tank oil in these fields is 45° API with a bubble point pressure of 122 kg/cm^2 absolute and a solution gas-oil ratio of 141 Std m^3/ST_2m^3. The initial reservoir pressure was 450 kg/cm^2 absolute at a datum of 3013 meters subsea. There was no initial gas cap nor was any secondary gas cap developed during any of the history matches or prediction cases that were investigated in the Zotti field. The initial oil and gas in place was 70 million cubic meters of stock tank oil and 10 billion cubic meters of solution gas at standard conditions.

PRODUCTION PROBLEMS

Several wells are currently shut-in or producing poorly due to the development of problems during the course of production. These well problems include influx of formation water, salt deposits in the tubing, asphaltene deposits, and various sediment accumulations in the wellbore. An interesting part of this study was the development of an indirect method of predicting when water influx reached a well. It is difficult to measure formation water production because of the fresh water injection system used to dissolve the salt in the wellbores, and the difficulty of isolating the wells for testing. Inspection of the well data from the area revealed that a sharp rise occurred in the oil salinity at the time the well's productivity began to decline. This rise in salinity is believed to be the result of water influx into the wellbore.

SIMULATION AND MATCH OF HISTORICAL DATA

The Zotti field was simulated with Fagin Associates International's Reservoir Performance Simulator or "RPS System." The particular reservoir simulator used in this study was a three-dimensional, three-phase, unsteady-state mathematical program which is used for analyzing reservoir engineering problems that are not involved with compositional changes. The basic mathematical description was originally reported in a paper by Fagin and Stewart[4] which described the implicit pressure-explicit saturation technique called IMPES.

These mathematics have been extensively modified through the years to include the many new developments in mathematical and computer techniques and the many various factors involved in solving general reservoir problems. Most of the theoretical analyses have been developed by the industry and most have been published by the Society of Petroleum Engineers. The RPS system is discussed in the appendix.

The basic steps of a study are shown on Figure 7 which depicts the various phases of work from data collection to the final report. The unusual feature of the Zotti field study was the three history matches that were obtained using different oil-in-place and relative permeability data. The first history match used the oil-in-place calculated from the geological description prior to the drilling of the delineation well AR-61. At the time this work was being done it was assumed that there was no water production in any of the wells during history and it was necessary to significantly modify the relative permeability functions in order to reduce the water saturation at the well blocks. Despite these modifications it appeared some wells should produce water. Subsequently, evidence of water in some of the wells was obtained and the reservoir was re-history matched using more typically shaped relative permeability curves. In order to obtain this history match a slight overall adjustment to the horizontal conductance was necessary. Several prediction cases were run based on this history match. But these cases had oil recoveries that were unusually high when compared to correlations for water drive reservoirs developed by Arps et al.[5] At this point in the study the geophysical and other data were reanalyzed and at about the same time the delineation well, AR-61, was drilled. Data from this well was used to re-interpret the structure map and corresponding petrophysical properties. The oil volume calculated using this new data was considerably larger than the initial oil volume and required that the field be re-history matched again. The third and final history match using the new oil volume and more realistically shaped relative permeability curves was obtained by making only slight changes to the aquifer size and horizontal conductances. The remaining phases of the study were completed in a normal manner.

In modeling the Zotti field two layers were used with a total of 612 active blocks. The quality of the lower layer was extremely poor but due to its large size, water influx could migrate vertically as the pressure declined. The two layers were defined primarily on the basis of reservoir quality. The upper layer, the R1-R2, had good porosity and permeability and was the principal flow zone. The poor quality zone, the R3 layer, was an expansion zone and contained only rock and water.

During the initial history runs on the Zotti field, the preliminary reservoir description produced well pressures that were less than those observed in the field. In order to bring these calculated pressures up it was necessary to adjust one or more of the reservoir parameters. The most likely candidates for adjustment were the overall permeability, the relative permeability curves, the aquifer size, and the initial oil volume. Experience has shown that the rock permeability can be adjusted over a wide range during the history matching procedure because of the uncertainties inherent in the distribution and the choice of cut-offs, the method of averaging, and the extrapolation beyond well control. In this case, an increase in the overall permeability would produce an increase in the pressures calculated for the field.

Increasing relative permeability to oil would have a similar effect and would allow the oil to move more readily toward the wells and the higher parts of the reservoir. Similarly, increasing the aquifer or oil volume in the model tends to reduce the calculated pressure decline, because of the added expansion of these fluids. Due to the greater compressibility of the oil and the low permeabilities in the aquifer, an increase in the oil volume has a greater effect than the same increase in the water volume would have.

In the initial history runs on the Zotti field, it was assumed that the initial oil volume was the best known of the parameters normally adjusted. Very little data was available to determine the shape of the relative permeability curves. The extent of the aquifer appeared fairly well defined by the regional geology of the area and after the initial runs the volume was adjusted slightly within the geologic limits.

Because of the absence of reported water production it was assumed that no water had reached the wells of this field. However, to inhibit the movement of water to the wells it became necessary to modify the relative permeability curves severely. Even with these changes the model indicated that several wells should be producing water. By increasing the overall permeability slightly and making minor adjustments to local conductance, a satisfactory match of the measured pressures was obtained.

Two points of this initial work appeared to require additional study. The first was the fact that the relative permeability curves had been modified to a somewhat unrealistic shape. The second point was that the percent oil recoveries appeared to be higher than would normally be expected for a field of this quality. Further research and field tests indicated that three wells were probably shut-in due to water encroachment although no production of water had been reported. This new information confirmed that water was flowing to the wells and allowed the relative permeability curves to be re-adjusted to a more normal shape. The initial and final relative permeability curves used in this study are shown in Figure 8. The field was history matched again, this time with all the adjustable parameters remaining within their expected limits. However, the percent recovery of the initial oil-in-place remained higher than appeared reasonable for a field of this quality.

In April 1978, a delineation well, AR-61, was drilled in the northern portion of the Zotti structure. This well revealed an important extension of the structure which confirmed that the reservoir was larger than was initially described. After a reevaluation of the field taking into account the new data obtained from this well and recent geophysical surveys, a new set of structure, thickness, and rock porosity and permeability maps were compiled. The result was an increase in the previous value of oil-in-place from 51 to 70 million stock tank cubic meters, or an increase of about 38 percent. This increase in the initial oil volume resulted in an excellent final history match after reducing the overall permeability of the field by about 40 percent and making minor adjustments to the local conductance. Some examples of well pressure matches are shown in Figure 6.

PREDICTION CASE RESULTS

Four prediction cases were run to January 1, 1997 for Zotti field using the RPS System and the final history match. After the final history match was obtained and the first prediction case run, it became obvious the strong water drive would produce high ultimate recoveries. The remaining three prediction cases were planned to accelerate recoveries and to investigate the advantages of a gas-lift operation. Two of the four cases assumed that natural depletion would continue and two cases assumed water injection would commence in 1981. In the two water injection cases, three additional producing wells and five injection wells were assumed to be drilled. In one natural depletion case and one water injection case artificial lift by gas-lift was assumed to commence in 1981. In each case, four of the existing wells were assumed to be worked over. Three of the workovers assumed the installation of cemented liners in an attempt to seal off zones that were producing water. A fracture workover was performed on well AR-1 to help improve the poor productivity which resulted from encountering a poor quality area of the reservoir. The production method, number of new wells drilled, number of injection wells, cumulative oil production and percent oil recovery to 1997 are shown on Table 2. Figure 5 shows the historical reservoir performance of Zotti field prior to 1978 and an example of predicted reservoir performance (Case II). These cases assumed successful well completions, workovers and control of well problems.

Oil recoveries to 1997 ranged from 33.4 percent to 38.3 percent in the cases investigated. Ultimate recoveries of 40.2 percent to 41.7 percent of initial stock tank oil-in-place were estimated by extrapolating the predicted reservoir performance results to a field rate of approximately 25 cubic meters per day. A recovery efficiency of 42.6 percent was calculated from a correlation developed by Arps et al.[5] for water drive reservoirs which is very close to the values obtained by extrapolation.

CONCLUSIONS

During the history matching procedure, the engineer must decide which parameters need to be adjusted, and it is important in such cases as the Zotti field to explore the sensitivity of the adjustment of the important parameters and then to develop guidelines as to maximum extent that they can be adjusted.

Because of the fact that the Zotti field has a strong water drive and had recovered only about 14.5 percent of the oil-in-place during history, it was concluded that the simulation of this field with a point-sink type of solution or with a one-dimensional model could have resulted in erroneous answers and possibly in inefficient recovery from the field.

It is most helpful in fields such as this to automatically calculate well production rates and water cuts during the history matching. These could be compared with measured values to help confirm reservoir data. In this case is was done manually. Predictions from pressure matches without considering the limits of the displacement process and the reservoir data may be misleading and inaccurate.

Predictions using multi-dimensional reservoir simulators provide realistic reservoir performance that is essential in planning future operations that consider economic and oil recovery objectives.

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APPENDIX

SIMULATION APPROACH

The mathematical approach to the RPS system was to devise a system of material balance equations around small space segments of a reservoir allowing for the flow of fluids in or out and arranging these equations in a form that could be solved for pressure.

The RPS system has several numerical procedures for solving the matrix problem. The ones tried in the Zotti problem were: 1) Alternating Direction Implicit Procedure (ADIP) developed by Brian[6] and Douglas[7] but expanded to include the ADIP Iterative Technique, 2) a modified Gaussian Elimination method, and, 3) Strongly Implicit Procedure (SIP). SIP was found to be fast and efficient for this problem. The mathematical approach sums the three continuity equations for each fluid phase to fit into a form that will be solved by the matrix solution procedure. The capillary pressure and gravity forces are included in the summation of the potential term. In addition, pseudo relative permeability curves and other data were developed for conditions between blocks and at wellbores. After each pressure calculation an explicit determination of saturation was made. This was repeated until a satisfactory solution was obtained. The work of Breitenbach[8], Hearn[9], Coats[10] and Jacks[11] describes various methods of approaching the complicated three-dimensional problems with a reduction in the space variables while minimizing the loss of reservoir performance definition. One of the different features about the RPS system is the technique it uses in simulating the gravity and capillary pressure potential terms that provides for a stable wedge zone between the various fluid phases of gas, oil and water and the method that can be varied to allow for the displacement of one fluid by another while these forces act. These features were believed to be important in the Zotti field because the oil in the upper layer was underlain by water and the low amount of dip creating a large wedge zone. The description of this feature is as follows. Consider the basic Darcy equation:

$$v = -\frac{k}{\mu}\frac{\partial \Phi}{\partial s} \qquad \ldots(1)$$

The potential function includes gravity, which is a function of density of the various fluids, capillary pressure, which is a function of the saturation contained in the blocks, etc., and pressure. The potential at any one point generally is written as:

$$\Phi_{i,j,k} = P_{i,j,k} + \rho D_{i,j,k} + (P_c)_{i,j,k} \quad \ldots(2)$$

In some cases the above may be adequate but in the case of Zotti it was important to provide for the wedge zone that moved as the viscous forces occurred during the production from the wells. Under normal flowing conditions the water moves along the bottom of the layer underriding the oil and then cusping upwards at the wellbore block until dynamic equilibrium between the gravity forces and the imposed drawdown pressure is attained. If the pressure drawdown is too great, the well will start coning or fingering water.

Considering the fluids as represented in Figure 9 where the gravity forces tend to cause the segregation of the fluids and the capillary pressure forces represent the forces between blocks manifested by the pressure in the phase in consideration minus the next most wetting phase, the following equation can be developed:

$$(\Phi_g)_{i,j,k} = P_{i,j,k} + (\rho_g D)_{i,j,k} \qquad \ldots(3)$$

$$(\Phi_o)_{i,j,k} = P_{i,j,k} + \rho_o (D-h_g)_{i,j,k} + (\rho_g h_g)_{i,j,k} + (P_{co})_{i,j,k} \qquad \ldots(4)$$

and

$$(\Phi_w)_{i,j,k} = P_{i,j,k} + \rho_w (D-h_g-h_o)_{i,j,k} + (\rho_g h_g)_{i,j,k} + (\rho_o h_o)_{i,j,k} + (P_{cw})_{i,j,k} \qquad \ldots(5)$$

The above drive potentials are a part of the basic equations that are solved for pressure in the IMPES technique. The height values that are a function of saturation are changed after each pressure calculation. The method of defining the heights of gas, oil and water as they change from the original conditions can vary depending upon the accuracy required.

The following example assumes that the gas cap has expanded and that the reservoir pressure is below the saturation pressure. The changing gas saturations within the block were described simply by the following:

$$\text{Total saturation} = S_g + S_w + S_o = 1.0$$

$$\text{Total area} = \text{Total saturation} \times h_t = h_t$$

$$\text{Where: } h_t = h_g + h_o + h_w$$

$$S_{gn} = \frac{\text{Area of Gas}}{\text{Total Area}} =$$

$$\frac{h_{gi}(1-S_{wc}) + \Delta h_g (1-S_{org}-S_{wc}) + (h_t-h_{gn}-h_{wi}) S_{gc}}{h_t} \quad \ldots(6)$$

$$\text{Where: } \Delta h_g = h_{gn} - h_{gi}$$

To determine the new gas height for equation 4 and 5 the above equation (6) was transformed to:

$$h_{gn} = \frac{h_t (S_{gn} - S_{gc}) - h_{gi} S_{org} + h_{wi} S_{gc}}{1 - S_{org} - S_{wc} - S_{gc}} \qquad \ldots(7)$$

For the above general formula various checks must be made to correct it for changing conditions. For instance if the gas cap is expanding but the pressure is above bubble point then the critical gas saturation, S_{gc}, must be set to zero. On the other hand, if the gas cap is shrinking the residual oil saturation in the gas zone, S_{org}, must be set to zero and so forth.

In similar fashion the equation for the height of the water can be developed as follows:

$$h_{wn} = \frac{h_t (S_w - S_{wc}) - h_{wi} (S_{orw} + S_{gc})}{1 - S_{wc} - S_{orw} - S_{gc}} \quad \ldots(8)$$

As in the gas equation, the h_{wn} equation has various tests designed to calculate the height at the proper condition. The height of the oil column is as follows:

$$h_{on} = h_t - h_{gn} - h_{wn} \quad \ldots(9)$$

The introduction of the gravity term is important. However, the problem of dynamically changing the average residual oil saturation behind the front in the calculation of the heights of the various fluids, of course, would be difficult, particularly if one were to account for heterogenous layering and for many other factors. However, correlation of average residual oil saturation versus petrophysical parameters is an easily obtainable correlation in comparison to a more accurate calculation. And, hopefully, the inaccuracy in this approach may possibly be improved through history matching technique.

In addition to the normal reservoir calculation the RPS system includes various routines to simulate flow up the wellbore and to the separation plants. These routines include gas-lift and water production caused by both the water used in the cleaning process and produced from the formation. After every time step material balance checks were made to determine the conditions of the calculation system. It was concluded that the RPS system simulated the dynamic forces and movements of fluids within the heterogenous system and it was a practical mathematical solution to the problem of the Zotti field.

NOMENCLATURE

D = depth subsea of block measured negatively
k = permeability, absolute
p = pressure at top of block
P_c = capillary pressure as a function of saturation and permeability, etc.
S = saturation
s = distance along direction of flow
v = velocity of fluid flow
μ = viscosity
Φ = potential term
ρ = average density between block i,j,k and any neighboring block

Subscripts

c = critical or connate
g = gas
i = initial
i,j,k = matrix point
n = a point in time
o = oil
r = average residual saturation behind front (dynamic)
t = total
w = water

TABLE 1 - RESERVOIR DATA

Datum depth, m subsea	3013
Reservoir temperature at datum, Centigrade	103°
Initial reservoir pressure at datum, kg/cm² absolute	450
Average reservoir pressure, January 1, 1978, kg/cm² abs	369
Saturation pressure, kg/cm² absolute	122
Weighted average arithmetic mean porosity	8.4%
Weighted average geometric mean permeability, md	14.7
Weighted average water saturation (in oil zone)	21.0%
Stock tank oil gravity, API	45°
Average depth to initial oil-water contact, m subsea	3065
Average initial oil reservoir thickness, m	31
Maximum initial oil reservoir thickness, m	70
Initial oil formation volume factor (flash), Res m^3/ST m^3	1.58
Initial gas-oil ratio (flash), Std m^3/ST m^3	141
Initial solution gas-in-place, Std $m^3 \times 10^9$	10
Initial oil-in-place, ST $m^3 \times 10^6$	70
Cumulative gas production, January 1, 1978, Std $m^3 \times 10^6$	1428
Cumulative oil production, January 1, 1978, ST $m^3 \times 10^6$	10.1
Oil recovery as of January 1, 1978	14.5%

TABLE 2 - PREDICTION CASE RESULTS

	Case I	Case II	Case III	Case IV
Production Method	Natural Depletion	Natural Depletion with Gas-Lift	Water Injection	Water Injection with Gas-Lift
Number of New Producing Wells	0	0	3	3
Number of Injection Wells	0	0	5	5
Cumulative Production to Jan. 1, 1997				
Oil, $m^3 \times 10^6$	23.4	24.3	26.1	26.8
Percent oil recovery	33.4	34.7	37.1	38.3

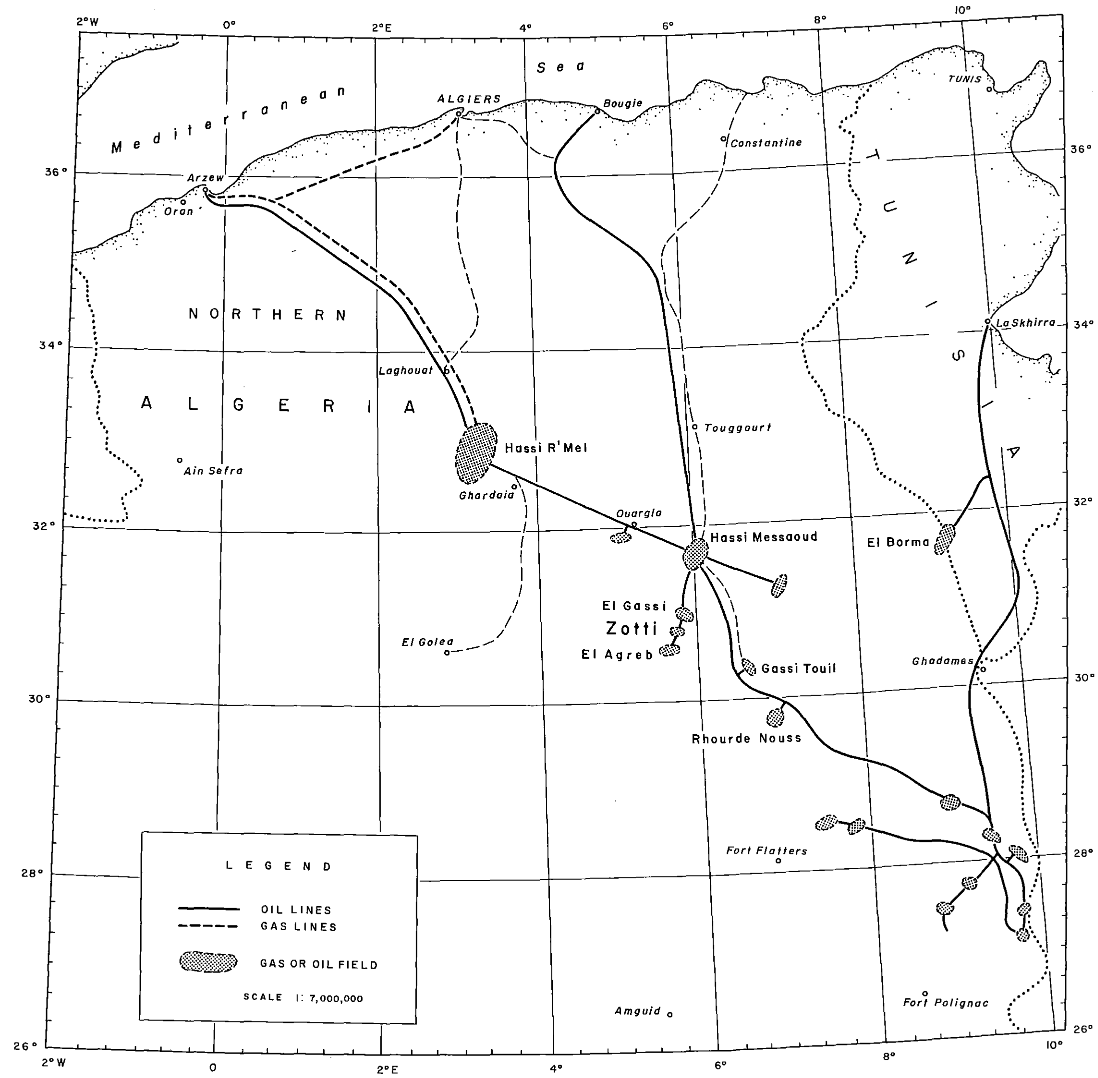

Fig. 1 - Location map.

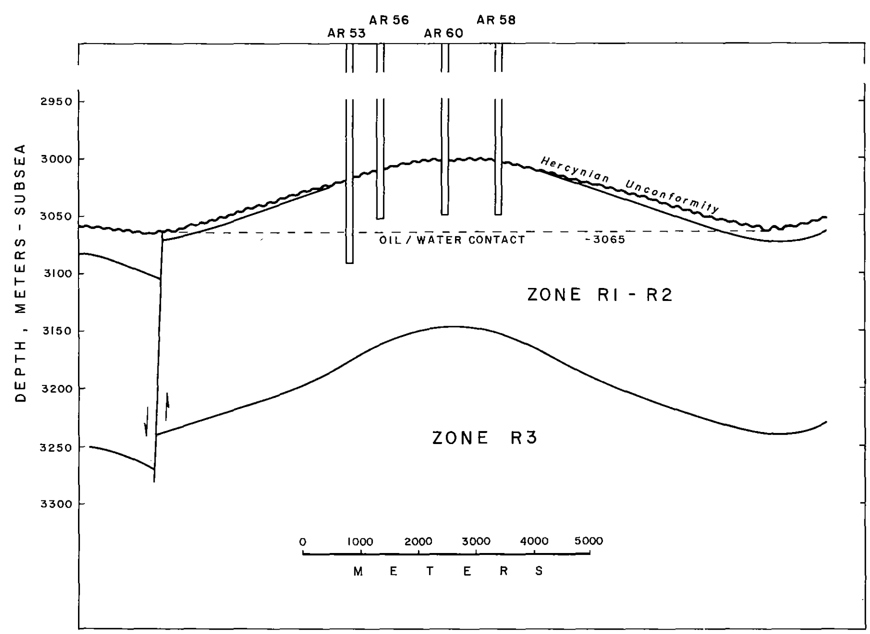

Fig. 2 - Cross-section of the Zotti Field.

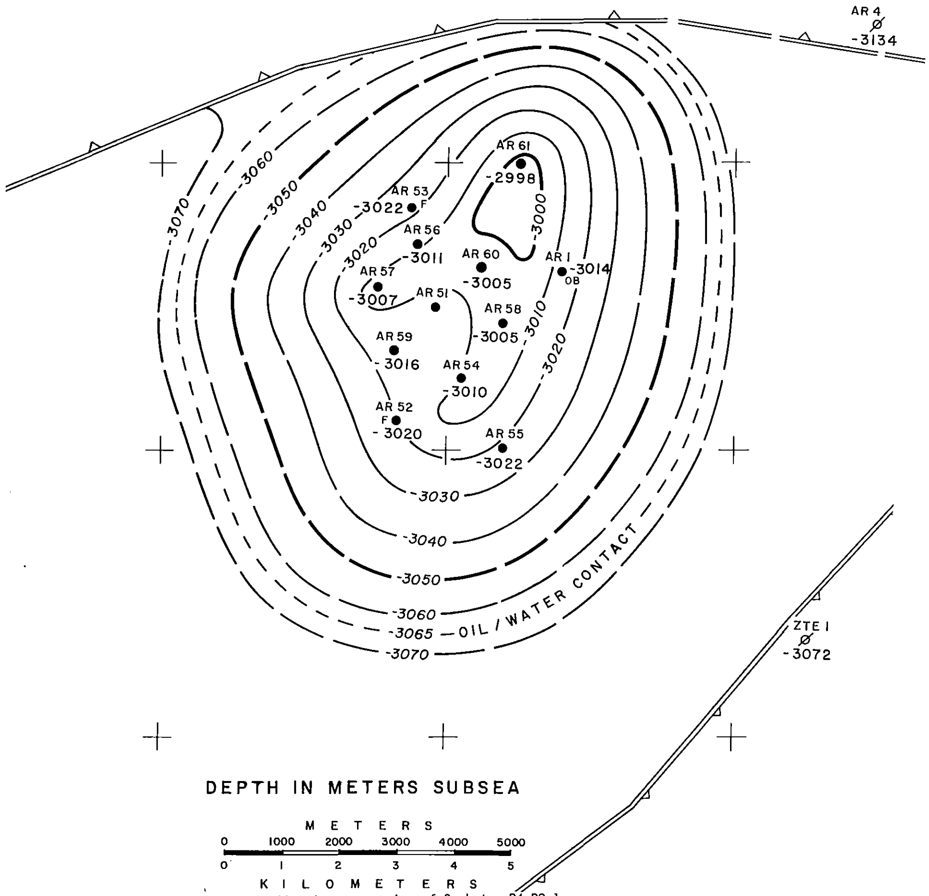

Fig. 3 - Structure map - top of Cambrian R1-R2 layer.

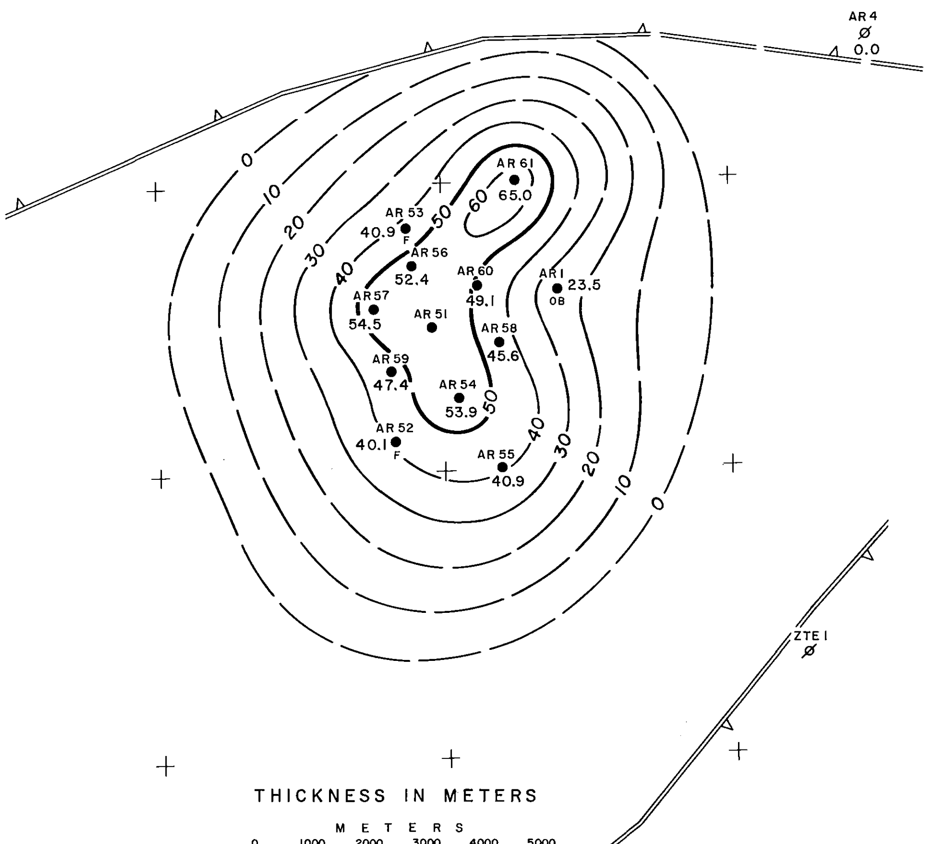

Fig. 4 - Net oil isopach map.

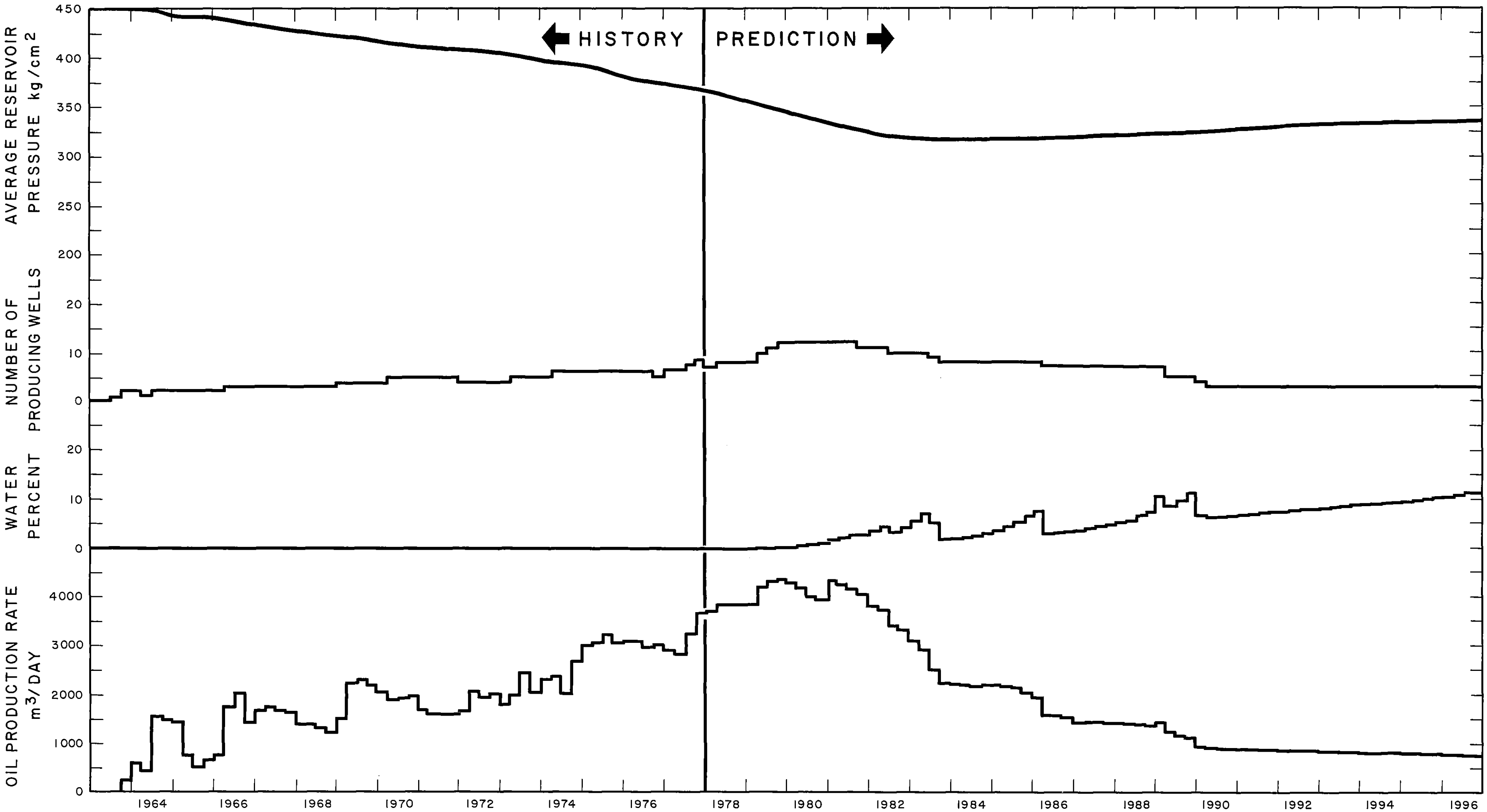

Fig. 5 – Total field performance – prediction case II.

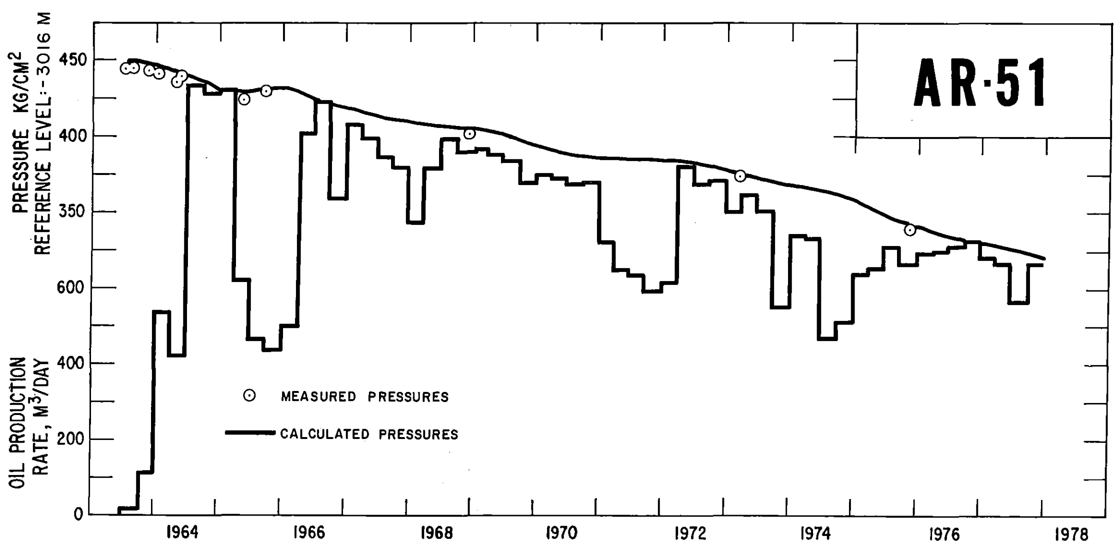

Fig. 6A - Examples of well performance with final history match pressures.

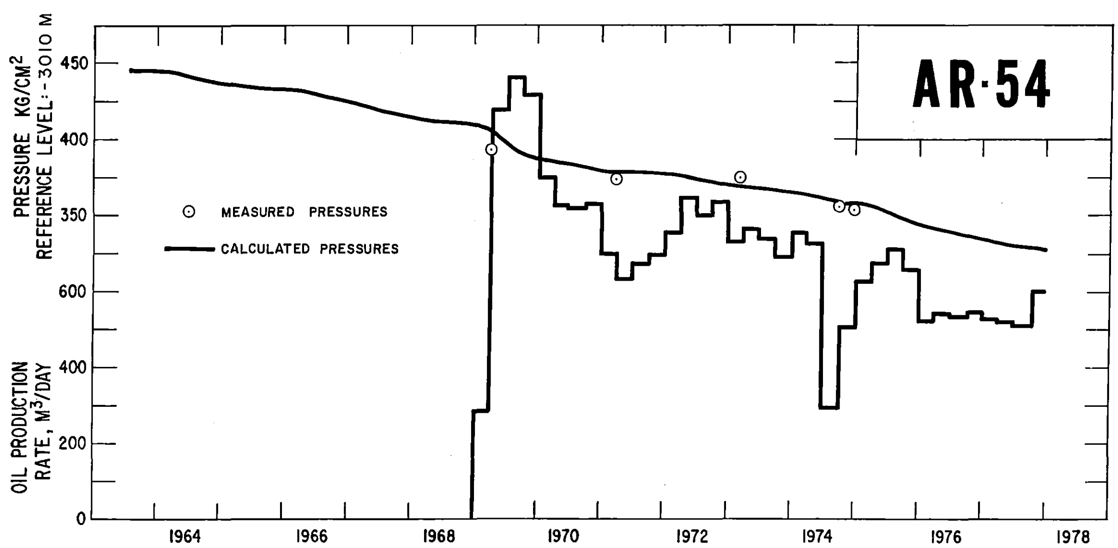

Fig. 6B - Examples of well performance with final history match pressures.

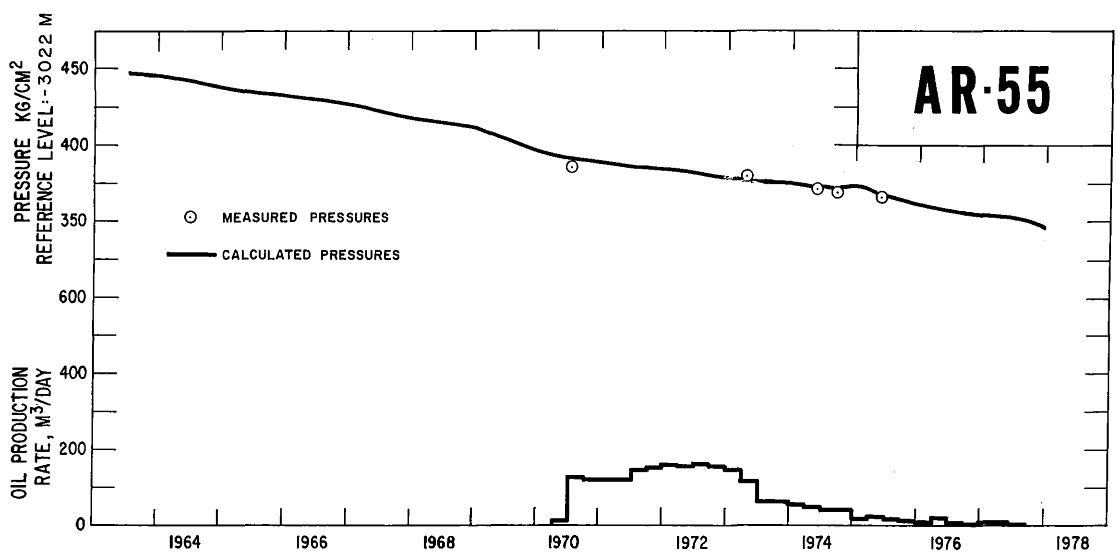

Fig. 6C - Examples of well performance with final history match pressures.

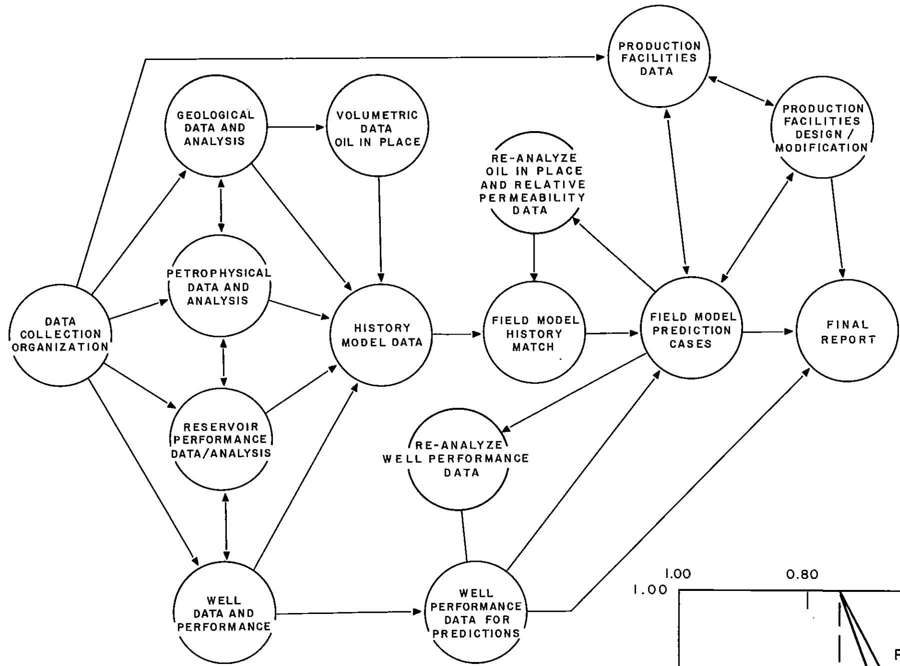

Fig. 7 - Reservoir study diagram.

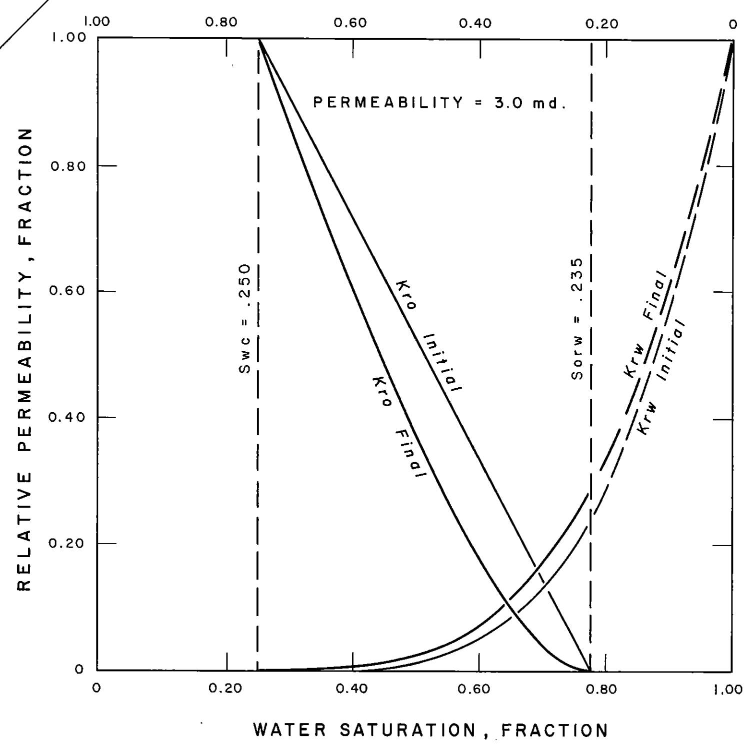

Fig. 8 - Comparison of relative permeability curves.

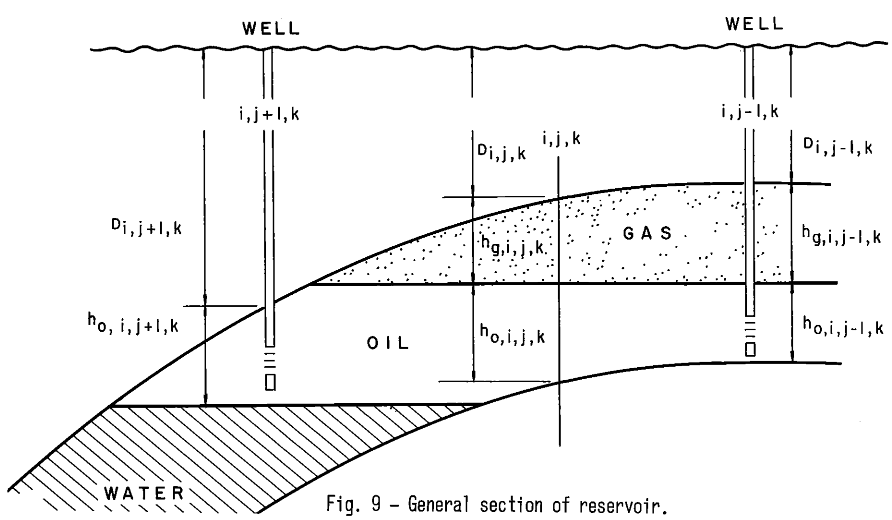

Fig. 9 - General section of reservoir.